Canadian Natural

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2016

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2016 FIRST QUARTER RESULTS

Commenting on first quarter 2016 results, Steve Laut, President of Canadian Natural stated, "The first three months of 2016 were operationally strong for Canadian Natural. The Company delivered production volumes within guidance and lower operating costs, with an operating cost reduction of 13% in E&P crude oil and NGLs and 14% in North America natural gas, on a per unit cost basis from Q1/15 levels. At Horizon, we achieved record low operating costs of $26.55/bbl and strong production volumes of approximately 128,000 bbl/d. Positive cash flow was delivered for all categories of our assets and reflects the strength of our diverse portfolio. The advancement of the Horizon Phase 2B expansion is progressing as planned and commissioning of certain Phase 2B systems commenced in March 2016. Our teams at Horizon are ready for execution of the scheduled 35 day major turnaround in early July 2016, where we will also tie in major components of Phase 2B. Following the turnaround, Phase 2B commissioning will continue in a staged approach to enhance the safe and effective targeted start-up of the expansion in October 2016."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "Cash flow of $657 million realized during the quarter was indicative of Canadian Natural's positive netbacks on a per BOE basis reflecting the Company's ability to respond quickly to unfavorable market changes through a flexible capital program and our commitment to achieving low cost structures. The first three months of 2016 reflected the lowest quarter for WTI benchmark pricing since the beginning of 2004, and yet the Company retained its investment grade status and maintained a strong balance sheet as we exited the quarter with a debt to book capitalization ratio of 38%."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2016	Dec 31 2015	Mar 31 2015
Net (loss) earnings	**$ (105)**	$ 131	$ (252)
Per common share – basic	**$ (0.10)**	$ 0.12	$ (0.23)
– diluted	**$ (0.10)**	$ 0.12	$ (0.23)
Adjusted net (loss) earnings from operations (1)	**$ (543)**	$ (49)	$ 21
Per common share – basic	**$ (0.50)**	$ (0.04)	$ 0.02
– diluted	**$ (0.50)**	$ (0.04)	$ 0.02
Cash flow from operations (2)	**$ 657**	$ 1,379	$ 1,370
Per common share – basic	**$ 0.60**	$ 1.26	$ 1.25
– diluted	**$ 0.60**	$ 1.26	$ 1.25
Capital expenditures, net of dispositions	**$ 1,040**	$ (96)	$ 1,412
Daily production, before royalties			
Natural gas (MMcf/d)	**1,786**	1,703	1,771
Crude oil and NGLs (bbl/d)	**546,927**	572,000	602,809
Equivalent production (BOE/d) (3)	**844,531**	855,800	898,053

(1) Adjusted net (loss) earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

- Canadian Natural realized cash flow from operations in Q1/16 of $657 million compared with $1,370 million for Q1/15 and $1,379 million for Q4/15. The decrease in Q1/16 from Q1/15 and Q4/15 primarily reflects lower benchmark pricing and lower sales volumes of North America crude oil and NGLs.
- For Q1/16, the Company had a net loss of $105 million compared to a net loss of $252 million in Q1/15 and net earnings of $131 million in Q4/15. Adjusted net loss from operations was $543 million in Q1/16 compared to adjusted net earnings of $21 million in Q1/15 and adjusted net loss of $49 million in Q4/15. Changes in adjusted net earnings (loss) primarily reflect the changes in cash flow from operations.
- Canadian Natural's corporate production volumes averaged 844,531 BOE/d in Q1/16, were comparable to Q4/15 levels and within the Company's guidance range of 829,000 BOE/d to 860,000 BOE/d. As expected, Q1/16 production volumes were 6% lower than Q1/15 levels due to natural production declines and a $315 million reduction in the Company's Exploration & Production ("E&P") net capital expenditures, representing a 46% decrease year over year.
- Crude oil and NGL production volumes averaged 546,927 bbl/d in Q1/16, within the Company's guidance range of 532,000 to 557,000 bbl/d.
  - During the quarter, strong operational performance at Horizon Oil Sands ("Horizon") continued and was demonstrated by quarterly production volumes averaging 127,909 bbl/d of synthetic crude oil ("SCO") and record low quarterly operating costs of $26.55/bbl (US$19.33/bbl).
  - International E&P quarterly crude oil production volumes averaged 49,031 bbl/d, representing a 35% and 2% increase over Q1/15 and Q4/15 levels.

- Infilling drilling programs at Espoir and Baobab increased Offshore Africa crude oil production volumes by 95% and 4% from Q1/15 and Q4/15 levels respectively. Overall, the programs were successful as production exceeded targets and costs were below original sanction targets. The drilling programs at Espoir and Baobab are now complete and International E&P crude oil production volumes are targeted to increase by 27% at the midpoint of 2016 annual guidance over 2015 levels.
- Continued success of production and waterflood optimization in the North Sea is reflected by maintaining crude oil production volumes in Q1/16 relative to Q1/15 and Q4/15 levels respectively. Quarterly crude oil operating costs for the North Sea averaged $47.69/bbl, reductions of 27% and 16% from Q1/15 and Q4/15 levels respectively, as a result of the Company's continued focus on effective and efficient operations.

- The Company achieved record quarterly natural gas volumes of 1,786 MMcf/d, 1% and 5% higher than Q1/15 and Q4/15 levels respectively. North America natural gas operating costs in Q1/16 averaged $1.18/Mcf compared to $1.38/Mcf in Q1/15, representing a 14% decrease which reflects a continued focus on cost optimization.
- The Company continues to execute capital discipline by proactively managing its crude oil and natural gas drilling programs. In Q1/16, the Company's drilling activity consisted of 12 net wells compared to 53 net wells in Q1/15, a 77% decrease while Q1/16 production volumes decreased by 6% to 844,531 BOE/d from 898,053 BOE/d in Q1/15.
- During Q1/16, Canadian Natural continued to realize positive results from its commitment to the enhancement of its effective and efficient operations. A comparison of per unit operating cost reductions achieved in the quarter is demonstrated below.

Operating Costs (Canadian $)	**Q1/16**	Q1/15	**Year-over-Year Percent Reduction**
North America Light Crude Oil and NGLs ($/bbl)	**$ 12.87**	$ 16.23	**21%**
Pelican Lake Heavy Crude Oil ($/bbl)	**$ 6.92**	$ 8.62	**20%**
Primary Heavy Crude Oil ($/bbl)	**$ 13.12**	$ 17.21	**24%**
Thermal Oil Sands In Situ ($/bbl)	**$ 10.60**	$ 10.64	**–**
Horizon Oil Sands Mining and Upgrading ($/bbl)	**$ 26.55**	$ 29.73	**11%**
North Sea Light Crude Oil ($/bbl)	**$ 47.69**	$ 65.23	**27%**
North America Natural Gas ($/Mcf)	**$ 1.18**	$ 1.38	**14%**
Total Overall ($/BOE)	**$ 13.45**	$ 15.69	**14%**

- Due to the timing of liftings from the various fields in Offshore Africa that have different cost structures, and a weaker Canadian dollar, a quarterly cost comparison for Offshore Africa year over year is not indicative of performance. However, on an annual basis, due to a continued focus on effective and efficient operations, Offshore Africa crude oil operating costs are targeted to reduce by 50% on a produced barrel basis, based on the midpoint of the Company's 2016 annual guidance over 2015.
- In early July 2016, the Company targets to begin a scheduled 35 day major turnaround at Horizon to complete maintenance activities within the plant facilities. Planning activities for the turnaround are complete, and the teams and systems are in place and ready to execute. Concurrent with the completion of maintenance activities, tie in of the major components of the Horizon Phase 2B expansion will be accomplished during the planned outage.
- 2016 is a milestone year for Canadian Natural as the Company advances the completion of the Horizon expansion with the addition of 45,000 bbl/d of SCO from Phase 2B, targeted to start up in 5 months. With the completion of Phase 2B, Canadian Natural expects Horizon's 2016 exit nameplate capacity to be rated at 182,000 bbl/d of SCO with a targeted utilization rate range of 92% to 96%, resulting in a step change in the sustainability of the production and cash flow profiles for the Company.

- Construction execution of the Horizon Phase 2B expansion is progressing as scheduled and at March 31, 2016, achieved 84% physical completion. Commissioning activities of the plant systems commenced in March 2016 and are on schedule. The Phase 2B expansion's commissioning plan will be a staged approach, and the targeted completion of commissioning for all systems are as follows; 20% by May 2016, 60% by June 2016 and 80% by July 2016. Commissioning in the latter half of Q3/16 will primarily consist of non-critical, non-process systems.

- By taking a staged approach to commissioning of the plant systems, the Company is able to enhance the safe and effective start-up of the expansion in October 2016. The commissioning teams have been in place for over 2 years with key Horizon operational personnel in place for approximately 1.5 years, ensuring that the Company has the ability to complete construction and effectively commission and start up Horizon Phase 2B on schedule and on budget.

- Horizon project capital in 2016 is targeted to range from $1.89 billion to $1.99 billion, the majority of which will be spent over the first nine months of 2016. Horizon project costs in Q1/16 totalled $422 million. In 2017, Horizon project capital costs are targeted to decline to approximately $1 billion for Phase 3 completion, which is targeted to add incremental production volumes of 80,000 bbl/d in Q4/17. The addition of Phase 3 marks the completion of the current Horizon expansion. Canadian Natural's total Horizon production volumes are targeted to average 250,000 bbl/d of SCO with operating costs trending below C$25.00/bbl (US$19.38/bbl).

▪ Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at March 31, 2016, the Company had in place bank credit facilities of approximately $7.4 billion, of which approximately $2.3 billion was undrawn and available.

▪ Canadian Natural maintained its strong balance sheet with debt to book capitalization of 38% at March 31, 2016, equivalent to December 31, 2015 levels, despite Q1/16 WTI pricing of US$33.51/bbl and AECO pricing of $2.00/GJ.

▪ Canadian Natural declared a quarterly cash dividend on its common shares of C$0.23 per share payable on July 1, 2016.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate effective and efficient operations, Canadian Natural focuses its activities in core regions where the Company owns a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning and operating associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Furthermore, the Company maintains large project inventories and production diversification among each of the commodities it produces; light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

Drilling Activity

	Three Months Ended Mar 31			
	2016		2015	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**11**	**8**	48	42
Natural gas	**5**	**4**	13	9
Dry	**–**	**–**	2	2
Subtotal	**16**	**12**	63	53
Stratigraphic test / service wells	**199**	**199**	121	86
Total	**215**	**211**	184	139
Success rate (excluding stratigraphic test / service wells)		**100%**		96%

▪ As a direct result of the decrease in crude oil and natural gas pricing, the Company's flexible capital allocation program and other external events, the Company proactively reduced its 2016 drilling programs. Drilling activity, excluding strat/service wells, in Q1/16 consisted of 12 net wells compared to 53 net wells in Q1/15.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGL production (bbl/d)	**251,943**	259,873	286,333
Net wells targeting crude oil	**7**	1	40
Net successful wells drilled	**7**	1	38
Success rate	**100%**	100%	95%

- Q1/16 production volumes of North America crude oil and NGLs averaged 251,943 bbl/d, representing an expected decrease of 12% and 3% from Q1/15 and Q4/15 levels. The year over year production decline was modest considering an 83% reduction in drilling activity from 40 net wells in Q1/15 to 7 net wells in Q1/16.
- North America light crude oil and NGL quarterly production averaged 90,067 bbl/d in Q1/16, representing a 7% decrease from Q1/15 levels and comparable to Q4/15 levels.
- Quarterly production volumes from Pelican Lake operations averaged 47,612 bbl/d, representing a 7% and 4% decrease from Q1/15 and Q4/15 levels respectively. The slight decrease in production from Q4/15 was due to downtime associated with increased wellbore cleanouts of injection and production wells, reduced polymer injection in some areas to improve reservoir conformance and natural production declines of non-polymer flooded areas of the field. Production volumes are currently exceeding 49,000 bbl/d. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.
- Q1/16 primary heavy crude oil production averaged 114,264 bbl/d, a decrease of 17% and 5%, as expected, from Q1/15 and Q4/15 levels. This production decline reflects the Company's proactive decision to reduce its primary heavy crude oil drilling program since 2014. Additionally during the quarter, as a result of unfavorable economic conditions, an average of approximately 900 bbl/d of primary heavy crude oil production volumes was shut in. In Q1/16, 6 net wells were drilled compared to 36 net wells in Q1/15.
- Canadian Natural continued to realize reduced quarterly operating costs of its North America E&P crude oil and NGL products on a per unit basis in Q1/16 from Q1/15 levels.
  - North America light crude oil and NGL quarterly operating costs were reduced by 21%.
  - At Pelican Lake, industry leading operating costs of $6.92/bbl were achieved, representing a 20% decrease.
  - Strong operating cost reductions of 24% were realized within the primary heavy crude oil operations.
- The Company's North America E&P crude oil and NGL annual production guidance is targeted to range from 235,000 bbl/d - 245,000 bbl/d in 2016.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Bitumen production (bbl/d)	**118,044**	135,135	146,086
Net wells targeting bitumen	**–**	–	3
Net successful wells drilled	**–**	–	3
Success rate	**–**	–	100%

- Thermal in situ quarterly production achieved strong volumes of 118,044 bbl/d in Q1/16, slightly above the midpoint of the Company's guidance range, representing a decrease of 19% and 13% from Q1/15 and Q4/15 levels. The decrease in production volumes reflect reduced drilling programs at Primrose since 2014 and the temporary curtailment of production volumes at Primrose East.

- Canadian Natural has a comprehensive pipeline and proactive inspection program and as a result of inspection of an above-ground pipeline, pipeline cracks were observed in January 2016 at Primrose East. Production volumes of approximately 15,000 bbl/d were temporarily shut in to allow for investigation, engineering assessment and repair of the pipeline. The Company now targets to ramp up Primrose East production volumes commencing in May 2016.

- Q1/16 production volumes at Kirby South averaged 34,570 bbl/d. Production was affected in the quarter as a result of a third party power outage in late December causing damage to three evaporators at the Kirby South facility. Repair of the evaporators was completed and production ramped up in March 2016. Current production volumes are approximately 38,000 bbl/d with a steam to oil ratio ("SOR") of 2.7.

- The Alberta Energy Regulator's ("AER") final investigation report on the Primrose flow to surface events was released on March 21, 2016. The AER's report is consistent with Canadian Natural's interim Causation Report submitted to the AER on June 27, 2014 as well as Canadian Natural's Final Report submitted on April 1, 2015.

Natural Gas

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Natural gas production (MMcf/d)	**1,722**	1,635	1,713
Net wells targeting natural gas	**4**	4	9
Net successful wells drilled	**4**	4	9
Success rate	**100%**	100%	100%

- Record North America natural gas quarterly production volumes averaging 1,722 MMcf/d were achieved in Q1/16, an increase of 1% and 5% from Q1/15 and Q4/15 levels respectively. The increase from Q4/15 to Q1/16 levels reflects the reinstatement of production following third party pipeline transportation restrictions in 2015, partially offset by the impact of shut-in volumes of approximately 43 MMcf/d resulting from uneconomic natural gas pricing and continued third party pipeline transportation restrictions. Additionally, approximately 22 MMcf/d was shut in due to an unplanned restriction at a third party processing facility in Northeast British Columbia ("NE BC"), which is expected to impact Q2/16 production volumes by approximately 20 MMcf/d.

- Operations at Septimus, Canadian Natural's liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations, with industry leading operating costs of $0.21/Mcfe in Q1/16.

- North America natural gas quarterly operating costs were $1.18/Mcf in Q1/16, a 14% decrease from Q1/15 levels of $1.38/Mcf, reflecting a continued focus on cost optimization.

- In response to current natural gas pricing, the Company targets to shut in additional volumes throughout the remainder of 2016 of approximately 40 MMcf/d, primarily related to properties with high third party processing fees. Consequently, the Company's total natural gas annual production guidance has been revised and is targeted to range from 1,725 MMcf/d - 1,785 MMcf/d in 2016.

International Exploration and Production

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil production (bbl/d)			
North Sea	**23,317**	23,110	23,036
Offshore Africa	**25,714**	24,832	13,188
Natural gas production (MMcf/d)			
North Sea	**29**	36	34
Offshore Africa	**35**	32	24
Net wells targeting crude oil	**1.2**	1.2	0.6
Net successful wells drilled	**1.2**	1.2	0.6
Success rate	**100%**	100%	100%

- International crude oil production averaged 49,031 bbl/d in Q1/16, an increase of 35% and 2% from Q1/15 and Q4/15 levels, respectively. The increase in production volumes from Q1/15 levels was primarily due to additional wells coming onstream during 2015 and Q1/16 as part of the infill drilling programs at the Baobab and Espoir fields. Production volumes were relatively flat compared to Q4/15 levels due to the impact of a temporary shut-in at the Baobab field due to a riser failure in late December 2015, which was reinstated in late January 2016 after inspection of the riser system. International E&P crude oil Q2/16 production volumes are targeted to range from 55,000 bbl/d – 60,000 bbl/d, representing a 17% increase at the midpoint over Q1/16 levels.
- Infilling drilling programs at Espoir and Baobab increased Offshore Africa crude oil production volumes by 95% and 4% from Q1/15 and Q4/15 levels respectively. Overall, the programs were successful as production exceeded targets and costs were below original sanction targets. The drilling programs at Espoir and Baobab are now complete and International E&P crude oil annual production volumes are targeted to increase by 27% at the midpoint of 2016 annual guidance over 2015 levels.
- Continued success of production and waterflood optimization in the North Sea is reflected by maintaining crude oil production volumes in Q1/16 relative to Q1/15 and Q4/15 levels respectively. Quarterly crude oil operating costs for the North Sea averaged $47.69/bbl, reductions of 27% and 16% from Q1/15 and Q4/15 levels respectively, as a result of the Company's continued focus on effective and efficient operations.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Synthetic crude oil production (bbl/d) (1)	**127,909**	129,050	134,166

(1) The Company produces diesel for internal use at Horizon. First quarter 2016 SCO production before royalties excludes 2,562 bbl/d of SCO consumed internally as diesel (fourth quarter 2015 – 2,337 bbl/d; first quarter 2015 – 1,676 bbl/d).

- Horizon's strong operational performance continued in Q1/16 as production volumes averaged 127,909 bbl/d of SCO, which met the upper end of the Company's production guidance of 122,000 bbl/d – 128,000 bbl/d.
- The Company achieved record low quarterly operating costs at Horizon of $26.55/bbl (US$19.33/bbl), an 11% reduction from Q1/15 levels, as a result of safe, steady and reliable operations and a focus on continuous improvement during the quarter.
- In early July 2016, the Company targets to begin a scheduled 35 day major turnaround at Horizon to complete maintenance activities within the plant facilities. Planning activities for the turnaround are complete, and the teams and systems are in place and ready to execute. Concurrent with the completion of maintenance activities, tie in of major components of the Horizon Phase 2B expansion will be accomplished during the planned outage.

- The Horizon Phase 2B expansion is targeted to add 45,000 bbl/d of SCO production capacity. Construction execution of the Horizon Phase 2B expansion is progressing as scheduled and at March 31, 2016, achieved 84% physical completion. Commissioning activities of the plant systems commenced in March 2016 and are on schedule. The Phase 2B expansion's commissioning plan will be a staged approach, and the targeted completion of commissioning for all systems are as follows; 20% by May 2016, 60% by June 2016 and 80% by July 2016. Commissioning in the latter half of Q3/16 will primarily consist of non-critical, non-process systems.

- By taking a staged approach to commissioning of the plant systems, the Company is able to enhance the safe and effective start-up of the expansion in October 2016. The commissioning teams have been in place for over 2 years with key Horizon operational personnel in place for approximately 1.5 years, ensuring that the Company has the ability to complete construction and effectively commission and start up Horizon Phase 2B on schedule and on budget.

- The Phase 3 expansion is currently on budget and on schedule. This Phase is 79% physically complete, and includes the addition of extraction trains and combined hydrotreater. Phase 3 is targeted to increase production capacity by 80,000 bbl/d in Q4/17 and will result in additional reliability, redundancy and significant operating cost savings for the Horizon project.

- Directive 74 of the Horizon expansion includes research into tailings management and technological investment. This project remains on track and is 59% physically complete.

MARKETING

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGL pricing			
WTI benchmark price (US$/bbl) (1)	**$ 33.51**	$ 42.17	$ 48.57
WCS blend differential from WTI (%) (2)	**42%**	34%	30%
SCO price (US$/bbl)	**$ 33.77**	$ 42.77	$ 45.26
Condensate benchmark pricing (US$/bbl)	**$ 34.45**	$ 41.67	$ 45.59
Average realized pricing before risk management (C$/bbl) (3)	**$ 23.31**	$ 33.90	$ 37.03
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.00**	$ 2.51	$ 2.80
Average realized pricing before risk management (C$/Mcf)	**$ 2.23**	$ 2.96	$ 3.38

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**WCS Blend Differential from WTI (US$/bbl)**	**SCO Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**	**1 CAD=X USD average exchange rate**
2016						
January	$ 31.78	43.7%	$ (13.90)	$ (0.03)	$ 2.85	$ 0.7031
February	$ 30.62	46.8%	$ (14.32)	$ (0.46)	$ 1.25	$ 0.7248
March	$ 37.96	38.2%	$ (14.50)	$ 1.20	$ (1.27)	$ 0.7561
April	$ 41.13	32.2%	$ (13.24)	$ 4.73	$ (0.56)	$ 0.7801
May*	$ 46.14	30.9%	$ (14.28)	$ (0.21)	$ (0.15)	$ 0.7976
June*	$ 46.83	28.9%	$ (13.55)	$ 0.00	$ (3.50)	$ 0.7973

**Based on current indicative pricing as at May 1, 2016. Monthly USD/CAD exchange rates are based upon the average noon rates for each month. For June, the USD/CAD exchange rate was based upon the forward curve rate based on May 1, 2016 spot rate.*

- Q1/16 WTI pricing averaged US$33.51/bbl as compared to US$48.57/bbl in Q1/15. Volatility in supply and demand factors and geopolitical events remain primary factors in the current WTI and Brent pricing environment. The Organization of the Petroleum Exporting Countries' ("OPEC") decision not to curtail oil production to offset the excess world supply resulted in a year over year decline in benchmark pricing.

- In Q1/16, the WCS differential to WTI averaged US$14.24/bbl or 42% as compared to Q1/15 of US$14.75/bbl or 30%. May 2016 and June 2016 indications of the WCS blend differential of US$14.28/bbl or 31% and US$13.55/bbl or 29% respectively, are normal given the trending WTI price curve. Seasonal demand fluctuations, changes in transportation logistics and refinery utilization and shutdowns will continue to be reflected in WCS pricing.

- Canadian Natural contributed approximately 226,000 bbl/d of its heavy crude oil stream to the WCS blend in Q1/16. The Company remains the largest contributor to the WCS blend, accounting for 52% of the total blend.

- Q1/16 SCO pricing averaged US$33.77/bbl in Q1/16 as compared to US$45.26/bbl in Q1/15 and US$42.77/bbl in Q4/15. Fluctuations in SCO pricing during Q1/16 were a result of changes in WTI benchmark pricing and unplanned industry upgrader outages.

- Q1/16 AECO pricing averaged $2.00/GJ, decreasing by 29% and 20% from $2.80/GJ and $2.51/GJ in Q1/15 and Q4/15 respectively. The decrease in natural gas prices in Q1/16 compared with Q1/15 and Q4/15 was primarily due to warmer than normal winter temperatures in 2016. US natural gas inventories were at near record high levels at the end of the winter season. Strong natural gas production volumes in North America continue to put pressure on natural gas prices. Natural gas prices are anticipated to remain volatile in the near future as a result of the excess inventory at the end of the 2015/2016 winter season.

NORTH WEST REDWATER UPGRADING AND REFINING

The North West Redwater refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. For project updates, please refer to: www.nwrpartnership.com/brief-updates.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 844,531 BOE/d for Q1/16, with approximately 96% of total production located in G8 countries.

- Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at March 31, 2016, the Company had in place bank credit facilities of approximately $7.4 billion, of which approximately $2.3 billion was undrawn and available.

  - In March 2016, Canadian Natural repaid US$500 million of US dollar denominated debt securities by drawing on its revolving bank facilities, net of cross currency contracts settled during the quarter.

- Canadian Natural maintained its strong balance sheet with debt to book capitalization of 38% at March 31, 2016, equivalent to December 31, 2015 levels, despite quarterly WTI pricing of US$33.51/bbl and AECO pricing of $2.00/GJ.

- Canadian Natural's estimate of its current production volumes attributed to its royalty portfolio is approximately 2,200 BOE/d, of which approximately 1,000 BOE/d are third party royalty volumes.

- In March 2016, the UK government enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. Subject to legislative approval, the UK government is also proposing to reduce the Supplementary Corporation Tax rate from 20% to 10% effective January 1, 2016.

- Canadian Natural declared a quarterly cash dividend on its common shares of C$0.23 per share payable on July 1, 2016.

- The Company has a strong balance sheet and cash flow generation which enables it to weather volatility in commodity prices. Canadian Natural retains additional capital expenditure program flexibility to proactively adapt to changing market conditions.

OUTLOOK

The Company forecasts 2016 production levels before royalties to average between 514,000 and 563,000 bbl/d of crude oil and NGLs and between 1,725 and 1,785 MMcf/d of natural gas. Q2/16 production guidance before royalties is forecast to average between 504,000 and 529,000 bbl/d of crude oil and NGLs and between 1,720 and 1,760 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months ended March 31, 2016 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended March 31, 2016 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, cash flow from operations, and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss), as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and cash flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three months ended March 31, 2016 in relation to the first quarter of 2015 and the fourth quarter of 2015. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2015, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated May 4, 2016.

FINANCIAL HIGHLIGHTS

		Three Months Ended		
($ millions, except per common share amounts)		**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Product sales		**$ 2,263**	$ 2,963	$ 3,226
Net earnings (loss)		**$ (105)**	$ 131	$ (252)
Per common share	– basic	**$ (0.10)**	$ 0.12	$ (0.23)
	– diluted	**$ (0.10)**	$ 0.12	$ (0.23)
Adjusted net earnings (loss) from operations (1)		**$ (543)**	$ (49)	$ 21
Per common share	– basic	**$ (0.50)**	$ (0.04)	$ 0.02
	– diluted	**$ (0.50)**	$ (0.04)	$ 0.02
Cash flow from operations (2)		**$ 657**	$ 1,379	$ 1,370
Per common share	– basic	**$ 0.60**	$ 1.26	$ 1.25
	– diluted	**$ 0.60**	$ 1.26	$ 1.25
Net capital expenditures (proceeds)		**$ 1,040**	$ (96)	$ 1,412

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings (loss) from operations. The reconciliation "Adjusted Net Earnings (loss) from Operations" presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings (loss) adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings (Loss) from Operations

($ millions)	Three Months Ended **Mar 31 2016**	Dec 31 2015	Mar 31 2015
Net earnings (loss) as reported	***$ (105)***	*$ 131*	*$ (252)*
Share-based compensation, net of tax [(1)]	***117***	*56*	*64*
Unrealized risk management loss, net of tax [(2)]	***63***	*128*	*9*
Unrealized foreign exchange (gain) loss , net of tax [(3)]	***(334)***	*170*	*413*
(Gain) loss from investments, net of tax [(4)(5)]	***(147)***	*23*	*15*
Gains on disposition of properties, net of tax [(6)]	***(23)***	*(627)*	*—*
Derecognition of exploration and evaluation assets, net of tax [(7)]	***—***	*70*	*—*
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities [(8)]	***(114)***	*—*	*(228)*
Adjusted net earnings (loss) from operations	***$ (543)***	*$ (49)*	*$ 21*

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

(4) The Company's investment in the 50% owned North West Redwater Partnership is accounted for using the equity method of accounting. Included in the non-cash (gain) loss from investments is the Company's pro rata share of the North West Redwater Partnership's accounting (gain) loss.

(5) The Company's investment in PrairieSky Royalty Ltd. ("PrairieSky") has been accounted for at fair value through profit and loss and is remeasured each period with changes in fair value recognized in net earnings.

(6) During the first quarter of 2016, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of exploration and evaluation assets. During the fourth quarter of 2015, the Company recorded a pre-tax gain of $690 million ($627 million after-tax) related to the disposition of a number of North America royalty income assets.

(7) In connection with the Company's notice of withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa in the fourth quarter of 2015, the Company derecognized $96 million ($70 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) During the first quarter of 2016 the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's deferred income tax liability of $114 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million.

Cash Flow from Operations

($ millions)	Three Months Ended **Mar 31 2016**	Dec 31 2015	Mar 31 2015
Net earnings (loss)	***$ (105)***	*$ 131*	*$ (252)*
Non-cash items:			
Depletion, depreciation and amortization	***1,219***	*1,472*	*1,355*
Share-based compensation	***117***	*56*	*64*
Asset retirement obligation accretion	***36***	*43*	*43*
Unrealized risk management loss	***74***	*174*	*14*
Unrealized foreign exchange (gain) loss	***(334)***	*170*	*413*
(Gain) loss from investments	***(147)***	*23*	*15*
Deferred income tax recovery	***(171)***	*(33)*	*(282)*
Gains on disposition of properties	***(32)***	*(690)*	*—*
Current income tax on disposition of properties	***—***	*33*	*—*
Cash flow from operations	***$ 657***	*$ 1,379*	*$ 1,370*

SUMMARY OF CONSOLIDATED NET EARNINGS (LOSS) AND CASH FLOW FROM OPERATIONS

The net loss for the first quarter of 2016 was $105 million compared with a net loss of $252 million for the first quarter of 2015 and net earnings of $131 million for the fourth quarter of 2015. The net loss for the first quarter of 2016 included net after-tax income of $438 million compared with net after-tax expenses of $273 million for the first quarter of 2015 and net after-tax income of $180 million for the fourth quarter of 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gains on disposition of properties, derecognition of exploration and evaluation assets and the effect of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net loss from operations for the first quarter of 2016 was $543 million compared with adjusted net earnings of $21 million for the first quarter of 2015 and an adjusted net loss of $49 million for the fourth quarter of 2015.

The decrease in adjusted net earnings (loss) for the first quarter of 2016 from the first quarter of 2015 was primarily due to:

- lower crude oil and NGLs and natural gas netbacks in the Exploration and Production segments;
- lower crude oil and NGL sales volumes in the North America segment;
- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower realized SCO prices;
- lower realized risk management gains; and
- higher realized foreign exchange losses;

partially offset by:

- lower depletion, depreciation and amortization expense in the Exploration and Production segments; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The increase in adjusted net loss for the first quarter of 2016 from the fourth quarter of 2015 was primarily due to:

- lower crude oil and NGLs and natural gas netbacks in the Exploration and Production segments;
- lower realized SCO prices;
- lower crude oil and NGLs sales volumes in the North America segment; and
- lower realized risk management gains;

partially offset by:

- higher natural gas sales volumes in the North America segment;
- lower depletion, depreciation and amortization expense in the Exploration and Production segments; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings (loss) and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the first quarter of 2016 was $657 million compared with $1,370 million for the first quarter of 2015 and $1,379 million for the fourth quarter of 2015. The fluctuations in cash flow from operations from the comparable periods were primarily due to the factors noted above relating to the decrease in adjusted net earnings (loss), as well as due to the impact of cash taxes.

Total production before royalties for the first quarter of 2016 decreased 6% to 844,531 BOE/d from 898,053 BOE/d for the first quarter of 2015 and decreased 1% from 855,800 BOE/d for the fourth quarter of 2015.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Mar 31 2016**		Dec 31 2015		Sep 30 2015		Jun 30 2015
Product sales	**$**	**2,263**	$	2,963	$	3,316	$	3,662
Net earnings (loss)	**$**	**(105)**	$	131	$	(111)	$	(405)
Net earnings (loss) per common share								
– basic	**$**	**(0.10)**	$	0.12	$	(0.10)	$	(0.37)
– diluted	**$**	**(0.10)**	$	0.12	$	(0.10)	$	(0.37)
($ millions, except per common share amounts)		Mar 31 2015		Dec 31 2014		Sep 30 2014		Jun 30 2014
Product sales	$	3,226	$	4,850	$	5,370	$	6,113
Net earnings (loss)	$	(252)	$	1,198	$	1,039	$	1,070
Net earnings (loss) per common share								
– basic	$	(0.23)	$	1.10	$	0.95	$	0.98
– diluted	$	(0.23)	$	1.09	$	0.94	$	0.97

Volatility in the quarterly net earnings over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of increased shale oil production in North America, fluctuating global supply/demand including the Organization of the Petroleum Exporting Countries' ("OPEC") decision not to curtail crude oil production to offset the excess world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the reduction in the Company's drilling program in North America, the impact and timing of acquisitions, and the impact of turnarounds at Horizon and higher drilling in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to third party pipeline restrictions and related pricing impacts, shut-in volumes due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, and turnarounds at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in international sales volumes subject to higher depletion rates, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to commodity volumes hedged and the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Changes in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on disposition of properties and investments** – Fluctuations due to the recognition of gains on disposition of properties in the various periods and fair value changes on the investment in PrairieSky shares.

BUSINESS ENVIRONMENT

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
WTI benchmark price (US$/bbl)	**$ 33.51**	$ 42.17	$ 48.57
Dated Brent benchmark price (US$/bbl)	**$ 33.92**	$ 43.59	$ 53.80
WCS blend differential from WTI (US$/bbl)	**$ 14.24**	$ 14.48	$ 14.75
WCS blend differential from WTI (%)	**42%**	34%	30%
SCO price (US$/bbl)	**$ 33.77**	$ 42.77	$ 45.26
Condensate benchmark price (US$/bbl)	**$ 34.45**	$ 41.67	$ 45.59
NYMEX benchmark price (US$/MMBtu)	**$ 2.04**	$ 2.28	$ 2.96
AECO benchmark price (C$/GJ)	**$ 2.00**	$ 2.51	$ 2.80
US/Canadian dollar average exchange rate (US$)	**$ 0.7282**	$ 0.7489	$ 0.8057

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("Brent") indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. For the first quarter of 2016, realized prices continued to be supported by the weaker Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales, as realized pricing is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$33.51 per bbl for the first quarter of 2016, a decrease of 31% from US$48.57 per bbl for the first quarter of 2015, and a decrease of 21% from US$42.17 per bbl for the fourth quarter of 2015.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$33.92 per bbl for the first quarter of 2016, a decrease of 37% from US$53.80 per bbl for the first quarter of 2015, and a decrease of 22% from US$43.59 per bbl for the fourth quarter of 2015.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply of crude oil in the world market contributed to a further decrease in crude oil benchmark pricing in the first quarter of 2016. OPEC's decision not to curtail crude oil production to offset the excess world supply continues to put downward pressure on benchmark pricing.

The WCS Heavy Differential averaged 42% for the first quarter of 2016 compared with 30% for the first quarter of 2015 and 34% for the fourth quarter of 2015. Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$33.77 per bbl for the first quarter of 2016, a decrease of 25% from US$45.26 per bbl for the first quarter of 2015, and a decrease of 21% from US$42.77 per bbl for the fourth quarter of 2015. The fluctuations in SCO pricing for the first quarter of 2016 from the comparable periods were primarily due to changes in WTI benchmark pricing and the impact of industry wide unplanned upgrader outages.

NYMEX natural gas prices averaged US$2.04 per MMBtu for the first quarter of 2016, a decrease of 31% from US$2.96 per MMBtu for the first quarter of 2015, and a decrease of 11% from US$2.28 per MMBtu for the fourth quarter of 2015.

AECO natural gas prices averaged $2.00 per GJ for the first quarter of 2016, a decrease of 29% from $2.80 per GJ for the first quarter of 2015, and a decrease of 20% from $2.51 per GJ for the fourth quarter of 2015.

The decrease in natural gas prices in the first quarter of 2016 compared with the first quarter of 2015 and the fourth quarter of 2015 was primarily due to warmer than normal winter temperatures in 2016. US natural gas inventories were at near record high levels at the end of the winter season. Strong natural gas production volumes continue to put pressure on natural gas prices. Natural gas prices are anticipated to remain volatile in the near term as a result of the excess inventory at the end of the 2015/2016 winter season.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**369,987**	395,008	432,419
North America – Oil Sands Mining and Upgrading (1)	**127,909**	129,050	134,166
North Sea	**23,317**	23,110	23,036
Offshore Africa	**25,714**	24,832	13,188
	546,927	572,000	602,809
Natural gas (MMcf/d)			
North America	**1,722**	1,635	1,713
North Sea	**29**	36	34
Offshore Africa	**35**	32	24
	1,786	1,703	1,771
Total barrels of oil equivalent (BOE/d)	**844,531**	855,800	898,053
Product mix			
Light and medium crude oil and NGLs	**16%**	16%	15%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**14%**	14%	15%
Bitumen (thermal oil)	**14%**	16%	16%
Synthetic crude oil (1)	**15%**	15%	15%
Natural gas	**35%**	33%	33%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)			
Crude oil and NGLs	**79%**	82%	80%
Natural gas	**21%**	18%	20%

(1) First quarter 2016 SCO production before royalties excludes 2,562 bbl/d of SCO consumed internally as diesel (fourth quarter 2015 – 2,337 bbl/d; first quarter 2015 – 1,676 bbl/d)

(2) Net of blending costs and excluding risk management activities.

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**331,313**	345,027	380,273
North America – Oil Sands Mining and Upgrading	**127,571**	127,968	132,413
North Sea	**23,264**	23,054	22,976
Offshore Africa	**24,578**	23,620	12,586
	506,726	519,669	548,248
Natural gas (MMcf/d)			
North America	**1,654**	1,568	1,643
North Sea	**29**	36	34
Offshore Africa	**34**	30	23
	1,717	1,634	1,700
Total barrels of oil equivalent (BOE/d)	**792,939**	792,083	831,637

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Crude oil and NGLs production for the first quarter of 2016 decreased 9% to 546,927 bbl/d from 602,809 bbl/d for the first quarter of 2015, and decreased 4% from 572,000 bbl/d for the fourth quarter of 2015. The decrease in crude oil and NGLs production from comparable periods primarily reflected lower drilling activity in North America and natural field declines, partially offset by optimization activities in various fields and increased production in the international segments. Crude oil and NGLs production for the first quarter of 2016 was within the Company's previously issued guidance of 532,000 to 557,000 bbl/d.

For 2016, annual production guidance is targeted to average between 514,000 and 563,000 bbl/d of crude oil and NGLs. Second quarter 2016 production guidance is targeted to average between 504,000 and 529,000 bbl/d of crude oil and NGLs.

Natural gas production for the first quarter of 2016 increased 1% to 1,786 MMcf/d from 1,771 MMcf/d for the first quarter of 2015, and increased 5% from 1,703 MMcf/d for the fourth quarter of 2015. The increase in natural gas production for the first quarter of 2016 from the first quarter of 2015 primarily reflected higher production in Offshore Africa and North America. The increase from the fourth quarter of 2015 was primarily due to increased production in the first quarter of 2016 following partial reinstatement of volumes related to third party pipeline transportation restrictions in 2015. Production volumes in the first quarter of 2016 were reduced by approximately 43 MMcf/d related to sustained low natural gas prices and continued third party pipeline transportation restrictions. Additionally, approximately 22 MMcf/d was shut in due to an unplanned restriction at a third party processing facility in Northeast British Columbia. These third party processing facility issues are expected to have a similar volume impact in the second quarter of 2016.

In response to current natural gas pricing, the Company targets to shut in additional volumes throughout the remainder of 2016 of approximately 40 MMcf/d, primarily related to properties with high third party processing fees. Annual production guidance has been revised and is now targeted to average between 1,725 and 1,785 MMcf/d.

Natural gas production for the first quarter of 2016 was within the Company's previously issued guidance of 1,780 to 1,820 MMcf/d. Second quarter 2016 production guidance is targeted to average between 1,720 and 1,760 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the first quarter of 2016 decreased 14% to 369,987 bbl/d from 432,419 bbl/d for the first quarter of 2015, and decreased 6% from 395,008 bbl/d for the fourth quarter of 2015. The decrease in production for the first quarter of 2016 from comparable periods primarily reflected lower drilling activity and natural field declines, partially offset by optimization activities in various fields. Crude oil and NGLs production for the first quarter of 2016 was within the Company's previously issued guidance of 363,000 to 377,000 bbl/d. Second quarter 2016 production guidance is targeted to average between 327,000 and 341,000 bbl/d of crude oil and NGLs.

Natural gas production for the first quarter of 2016 increased 1% to 1,722 MMcf/d from 1,713 MMcf/d for the first quarter of 2015, and increased 5% from 1,635 MMcf/d for the fourth quarter of 2015. The increase in natural gas production from the fourth quarter of 2015 was primarily due to the partial reinstatement of volumes related to third party pipeline transportation restrictions in 2015. Production volumes in the first quarter of 2016 reflected the impact of sustained low natural gas prices and continued third party pipeline transportation restrictions as well as additional volumes shut in due to an unplanned restriction at a third party processing facility in Northeast British Columbia. These third party processing facility issues are expected to have a similar volume impact in the second quarter of 2016.

North America – Oil Sands Mining and Upgrading

SCO production for the first quarter of 2016 was comparable with the fourth quarter of 2015 and decreased 5% to average 127,909 bbl/d compared with 134,166 bbl/d for the first quarter of 2015. Production in the first quarter of 2016 continued to reflect high utilization rates and reliability. As expected, the decrease from the first quarter of 2015 reflected planned maintenance in the first quarter of 2016. First quarter 2016 production of SCO was at the high end of the Company's previously issued guidance of 122,000 to 128,000 bbl/d. Second quarter 2016 production guidance is targeted to average between 122,000 and 128,000 bbl/d.

North Sea

North Sea crude oil production for the first quarter of 2016 of 23,317 bbl/d was comparable with 23,036 bbl/d for the first quarter of 2015 and 23,110 bbl/d for the fourth quarter of 2015 due to a focus on optimization activities, offsetting natural field declines.

Offshore Africa

Offshore Africa crude oil production for the first quarter of 2016 increased 95% to 25,714 bbl/d from 13,188 bbl/d for the first quarter of 2015, and increased 4% from 24,832 bbl/d for the fourth quarter of 2015. Production volumes increased for the first quarter of 2016 as an additional well came on stream at each of the Espoir and the Baobab fields during the quarter, partially offset by natural field declines as well as the impact of a temporary shut-in at the Baobab field due to a riser failure in late December 2015. After inspection of the riser system, production was reinstated in late January 2016.

International Guidance

The Company's North Sea and Offshore Africa first quarter 2016 crude oil production of 49,031 bbl/d was within the Company's previously issued guidance of 47,000 to 52,000 bbl/d. Second quarter 2016 production guidance is targeted to average between 55,000 and 60,000 bbl/d of crude oil.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

	Three Months Ended		
(bbl)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
North Sea	**667,879**	835,806	562,540
Offshore Africa	**1,830,976**	1,271,170	1,086,222
	2,498,855	2,106,976	1,648,762

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 23.31**	$ 33.90	$ 37.03
Transportation	**2.46**	2.61	2.46
Realized sales price, net of transportation	**20.85**	31.29	34.57
Royalties	**1.90**	3.49	3.83
Production expense	**13.94**	14.26	16.10
Netback	**$ 5.01**	$ 13.54	$ 14.64
Natural gas ($/Mcf) (1)			
Sales price (2)	**$ 2.23**	$ 2.96	$ 3.38
Transportation	**0.28**	0.38	0.36
Realized sales price, net of transportation	**1.95**	2.58	3.02
Royalties	**0.07**	0.10	0.12
Production expense	**1.23**	1.22	1.44
Netback	**$ 0.65**	$ 1.26	$ 1.46
Barrels of oil equivalent ($/BOE) (1)			
Sales price (2)	**$ 19.37**	$ 27.79	$ 30.57
Transportation	**2.20**	2.59	2.44
Realized sales price, net of transportation	**17.17**	25.20	28.13
Royalties	**1.30**	2.38	2.65
Production expense	**11.19**	11.55	13.20
Netback	**$ 4.68**	$ 11.27	$ 12.28

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 20.77**	$ 31.51	$ 35.22
North Sea	**$ 45.04**	$ 57.50	$ 64.59
Offshore Africa	**$ 42.99**	$ 53.37	$ 71.75
Company average	**$ 23.31**	$ 33.90	$ 37.03
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.05**	$ 2.73	$ 3.14
North Sea	**$ 7.02**	$ 9.53	$ 10.18
Offshore Africa	**$ 7.13**	$ 7.63	$ 11.70
Company average	**$ 2.23**	$ 2.96	$ 3.38
Company average ($/BOE) (1) (2)	**$ 19.37**	$ 27.79	$ 30.57

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

North America

North America realized crude oil prices averaged $20.77 per bbl for the first quarter of 2016, a decrease of 41% compared with $35.22 per bbl for the first quarter of 2015 and a decrease of 34% compared with $31.51 per bbl for the fourth quarter of 2015. The decrease in realized crude oil prices for the first quarter of 2016 from the comparable periods was primarily due to lower WTI benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, partially offset by the impact of a weakening Canadian dollar. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2016 contributed approximately 226,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 35% to average $2.05 per Mcf for the first quarter of 2016 compared with $3.14 per Mcf for the first quarter of 2015, and decreased 25% compared with $2.73 per Mcf for the fourth quarter of 2015.

The decrease in natural gas prices in the first quarter of 2016 compared with the first quarter of 2015 and the fourth quarter of 2015 was primarily due to warmer than normal winter temperatures in 2016. US natural gas inventories were at near record high levels at the end of the winter season. Strong natural gas production volumes continue to put pressure on natural gas prices. Natural gas prices are anticipated to remain volatile in the near term as a result of the excess inventory at the end of the 2015/2016 winter season.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Quarterly Average)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 28.30**	$ 36.45	$ 38.78
Pelican Lake heavy crude oil ($/bbl)	**$ 21.76**	$ 33.25	$ 36.21
Primary heavy crude oil ($/bbl)	**$ 19.63**	$ 31.14	$ 37.64
Bitumen (thermal oil) ($/bbl)	**$ 15.72**	$ 27.92	$ 30.25
Natural gas ($/Mcf)	**$ 2.05**	$ 2.73	$ 3.14

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices decreased 30% to average $45.04 per bbl for the first quarter of 2016 from $64.59 per bbl for the first quarter of 2015 and decreased 22% from $57.50 per bbl for the fourth quarter of 2015. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The decrease in realized crude oil prices for the first quarter of 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, partially offset by the weaker Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 40% to average $42.99 per bbl for the first quarter of 2016 from $71.75 per bbl for the first quarter of 2015 and decreased 19% from $53.37 per bbl for the fourth quarter of 2015. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The decrease in realized crude oil prices for the first quarter of 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, partially offset by the weaker Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 2.03**	$ 3.71	$ 4.02
North Sea	**$ 0.10**	$ 0.14	$ 0.16
Offshore Africa	**$ 1.90**	$ 2.61	$ 3.27
Company average	**$ 1.90**	$ 3.49	$ 3.83
Natural gas ($/Mcf) (1)			
North America	**$ 0.07**	$ 0.10	$ 0.12
Offshore Africa	**$ 0.32**	$ 0.44	$ 0.54
Company average	**$ 0.07**	$ 0.10	$ 0.12
Company average ($/BOE) (1)	**$ 1.30**	$ 2.38	$ 2.65

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and natural gas royalties for the first quarter of 2016 and the comparable periods reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 11% of product sales for the first quarter of 2016 compared with 12% for the first quarter of 2015 and 13% for the fourth quarter of 2015. The decrease in royalties for the first quarter of 2016 from comparable periods was primarily due to lower realized crude oil prices, offset by gas cost allowance adjustments on NGLs. North America crude oil and NGLs royalties per bbl are anticipated to average 7% to 9% of product sales for 2016.

Natural gas royalties averaged approximately 4% of product sales for the first quarter of 2016, consistent with comparable periods. Lower natural gas prices in the first quarter of 2016 were offset by gas cost allowance adjustments. North America natural gas royalties are anticipated to average 1.5% to 2.5% of product sales for 2016.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 4% for the first quarter of 2016 compared with 5% for the first quarter of 2015 and 5% for the fourth quarter of 2015. The decrease in royalties for the first quarter of 2016 from comparable periods was primarily a result of the timing of liftings from various fields and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 6% to 8% of product sales for 2016.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2016	Dec 31 2015	Mar 31 2015
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 11.46**	$ 11.45	$ 13.75
North Sea	**$ 47.69**	$ 56.97	$ 65.23
Offshore Africa	**$ 17.07**	$ 26.08	$ 15.46
Company average	**$ 13.94**	$ 14.26	$ 16.10
Natural gas ($/Mcf) (1)			
North America	**$ 1.18**	$ 1.17	$ 1.38
North Sea	**$ 4.09**	$ 3.27	$ 3.89
Offshore Africa	**$ 1.29**	$ 1.55	$ 2.80
Company average	**$ 1.23**	$ 1.22	$ 1.44
Company average ($/BOE) (1)	**$ 11.19**	$ 11.55	$ 13.20

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for the first quarter of 2016 decreased 17% to $11.46 per bbl from $13.75 per bbl for the first quarter of 2015 and was comparable with $11.45 per bbl for the fourth quarter of 2015. Production costs continued to reflect the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America crude oil and NGLs production expense is anticipated to average $11.25 to $12.25 per bbl for 2016.

North America natural gas production expense for the first quarter of 2016 decreased 14% to $1.18 per Mcf from $1.38 per Mcf for the first quarter of 2015 and was comparable with $1.17 per Mcf for the fourth quarter of 2015. Production costs continued to reflect the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America natural gas production expense guidance has been revised and is now anticipated to average $1.05 to $1.25 per Mcf for 2016.

North Sea

North Sea crude oil production expense for the first quarter of 2016 decreased 27% to $47.69 per bbl from $65.23 per bbl for the first quarter of 2015 and decreased 16% from $56.97 per bbl for the fourth quarter of 2015. The decrease in production expense for the first quarter of 2016 from comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, together with the impact of inventory valuation adjustments. North Sea crude oil production expense guidance has been revised and is now anticipated to average $40.50 to $46.50 per bbl for 2016.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2016 increased 10% to average $17.07 per bbl from $15.46 per bbl for the first quarter of 2015 and decreased 35% from $26.08 per bbl for the fourth quarter of 2015. The increase in production expense for the first quarter 2016 from first quarter 2015 was primarily due to the impact of foreign exchange. The decrease in production expense for the first quarter of 2016 compared with the fourth quarter of 2015 was primarily due to the timing of liftings from various fields, including the Olowi field, which have different cost structures, together with the impact of inventory valuation adjustments and the weaker Canadian dollar. Offshore Africa production expense guidance has been revised and is now anticipated to average $14.50 to $18.50 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Expense	**$ 1,069**	$ 1,330	$ 1,213
$/BOE (1)	**$ 16.60**	$ 19.95	$ 17.78

(1) Amounts expressed on a per unit basis are based on sales volumes.

The decrease in depletion, depreciation and amortization expense for the first quarter of 2016 from the first quarter of 2015 was primarily due to lower sales volumes and depletion rates in North America. The decrease from the fourth quarter of 2015 reflected the Company's derecognition of exploration and evaluation assets in Block CI-514 in Côte, d'Ivoire, Offshore Africa in the fourth quarter of 2015.

Depletion, depreciation and amortization expense on a per barrel basis for the first quarter of 2016 decreased 7% to $16.60 per BOE from $17.78 per BOE for the first quarter of 2015 and decreased by 17% from $19.95 per BOE for the fourth quarter of 2015. The decrease from the first quarter of 2015 was primarily due to lower depletion rates in North America. The decrease from the fourth quarter of 2015 reflected the impact of depletion expense related to Block CI-514 in Côte d'Ivoire, Offshore Africa in the fourth quarter of 2015.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Expense	**$ 29**	$ 35	$ 35
$/BOE (1)	**$ 0.45**	$ 0.54	$ 0.52

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the first quarter of 2016 decreased 13% to $0.45 per BOE from $0.52 per BOE for the first quarter of 2015, and decreased 17% from $0.54 per BOE for the fourth quarter of 2015.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the first quarter of 2016, operating performance continued to be strong, leading to average production of 127,909 bbl/d, reflecting high utilization rates and reliability. In the third quarter of 2016, Horizon will enter into a 35 day planned maintenance turnaround, resulting in a plant-wide shut down. The impact of the turnaround has been reflected in the Company's 2016 production, cash production cost and capital expenditure guidance.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($/bbl) (1)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
SCO sales price	**$ 46.63**	$ 57.49	$ 56.75
Bitumen value for royalty purposes (2)	**$ 11.29**	$ 24.37	$ 29.70
Bitumen royalties (3)	**$ 0.13**	$ 0.99	$ 1.01
Transportation	**$ 2.07**	$ 1.66	$ 1.83

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

(2) Calculated as the quarterly average of the bitumen valuation methodology price.

(3) Calculated based on bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $46.63 per bbl for the first quarter of 2016, a decrease of 18% compared with $56.75 per bbl for the first quarter of 2015 and a decrease of 19% compared with $57.49 per bbl for the fourth quarter of 2015. The decrease in SCO pricing for the first quarter of 2016 from the comparable periods was primarily due to movements in WTI benchmark pricing and the impact of industry wide unplanned upgrader outages.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 16 to the Company’s consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Cash production costs, excluding natural gas costs	**$ 282**	$ 326	$ 326
Natural gas costs	**15**	18	20
Cash production costs	**$ 297**	$ 344	$ 346

	Three Months Ended		
($/bbl) (1)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Cash production costs, excluding natural gas costs	**$ 25.17**	$ 27.10	$ 28.03
Natural gas costs	**1.38**	1.46	1.70
Cash production costs	**$ 26.55**	$ 28.56	$ 29.73
Sales (bbl/d)	**123,047**	130,990	129,433

(1) Amounts expressed on a per unit basis are based on sales volumes.

Cash production costs for the first quarter of 2016 averaged $26.55 per bbl, a decrease of 11% compared with $29.73 per bbl for the first quarter of 2015 and a decrease of 7% compared with $28.56 per bbl for the fourth quarter of 2015. The decrease in cash production costs for the first quarter of 2016 from comparable periods primarily reflected the Company’s continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs. Cash production costs are anticipated to average $27.00 to $30.00 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Depletion, depreciation and amortization	**$ 147**	$ 139	$ 139
$/bbl	**$ 13.11**	$ 11.48	$ 11.96

The increase in depletion, depreciation and amortization expense for the first quarter of 2016 from the first quarter of 2015 and the fourth quarter of 2015 partially reflected minor asset derecognitions in the first quarter of 2016.

Depletion, depreciation and amortization expense on a per barrel basis for the first quarter of 2016 increased 10% to $13.11 per bbl from $11.96 per bbl for the first quarter of 2015 and increased 14% from $11.48 per bbl for the fourth quarter of 2015. The increase in first quarter 2016 depletion, depreciation and amortization expense on a per barrel basis from comparable periods partially reflected minor asset derecognitions in the first quarter of 2016.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Expense	**$ 7**	$ 8	$ 8
$/bbl (1)	**$ 0.65**	$ 0.64	$ 0.66

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the first quarter of 2016 of $0.65 per bbl was comparable with the first quarter of 2015 and the fourth quarter of 2015.

MIDSTREAM

	Three Months Ended		
($ millions)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Revenue	**$ 26**	$ 33	$ 35
Production expense	**6**	7	9
Midstream cash flow	**20**	26	26
Depreciation	**3**	3	3
Equity (gain) loss from Redwater Partnership	**(26)**	12	15
Segment earnings before taxes	**$ 43**	$ 11	$ 8

The Company has a 50% interest in the North West Redwater Partnership ("Redwater Partnership"). Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2013, the Company, along with APMC, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). During the first quarter of 2016, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the first quarter of 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, and $300 million of 4.75% series G senior secured bonds due June 2037. As at March 31, 2016, Redwater Partnership had additional borrowings of $982 million under its secured $3,500 million syndicated credit facility.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

ADMINISTRATION EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Expense	**$ 86**	$ 93	$ 104
$/BOE (1)	**$ 1.14**	$ 1.18	$ 1.31

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the first quarter of 2016 decreased 13% to $1.14 per BOE from $1.31 per BOE for the first quarter of 2015 and decreased 3% from $1.18 per BOE for the fourth quarter of 2015. Administration expense per BOE decreased from the comparable periods primarily due to lower staffing related costs and general corporate costs, partially offset by the impact of lower recoveries due to the reduction in the capital expenditure program.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Expense	**$ 117**	$ 56	$ 64

The Company's stock option plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a $117 million share-based compensation expense for the three months ended March 31, 2016, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. For the three months ended March 31, 2016, the Company capitalized $23 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (March 31, 2015 – $14 million costs capitalized).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except per BOE amounts and interest rates)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Expense, gross	**$ 153**	$ 133	$ 144
Less: capitalized interest	**61**	60	58
Expense, net	**$ 92**	$ 73	$ 86
$/BOE (1)	**$ 1.22**	$ 0.93	$ 1.07
Average effective interest rate	**3.9%**	3.8%	4.0%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for the first quarter of 2016 increased from the first quarter of 2015 primarily due to the impact of higher overall debt levels, and increased from the fourth quarter of 2015 primarily due to the impact of interest on PRT recoveries in the North Sea in the fourth quarter of 2015. Capitalized interest of $61 million for the first quarter of 2016 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense on a per BOE basis for the first quarter of 2016 increased 14% to $1.22 per BOE from $1.07 per BOE for the first quarter of 2015 and increased 31% from $0.93 per BOE for the fourth quarter of 2015. The increase for the first quarter of 2016 from the first quarter of 2015 was primarily due to higher overall debt levels. The increase from the fourth quarter of 2015 was primarily due to interest on PRT recoveries in the North Sea in the fourth quarter of 2015.

The Company's average effective interest rate for the first quarter of 2016 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

	Three Months Ended		
($ millions)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Crude oil and NGLs financial instruments	**$ —**	$ (218)	$ (117)
Foreign currency contracts	**(4)**	(37)	(139)
Realized gain	**(4)**	(255)	(256)
Crude oil and NGLs financial instruments	**—**	189	12
Foreign currency contracts	**74**	(15)	2
Unrealized loss	**74**	174	14
Net loss (gain)	**$ 70**	$ (81)	$ (242)

During the first quarter of 2016, net realized risk management gains were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of $74 million ($63 million after-tax) on its risk management activities for the three months ended March 31, 2016, (December 31, 2015 – unrealized loss of $174 million; $128 million after-tax; March 31, 2015 – unrealized loss of $14 million; $9 million after-tax), primarily related to changes in the fair value of these contracts.

Complete details related to outstanding derivative financial instruments at March 31, 2016 are disclosed in note 14 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Net realized loss (gain)	**$ 19**	$ (5)	$ (53)
Net unrealized (gain) loss [1]	**(334)**	170	413
Net (gain) loss	**$ (315)**	$ 165	$ 360

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange loss for the three months ended March 31, 2016 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the three months ended March 31, 2016 was primarily related to the impact of a stronger Canadian dollar at quarter end with respect to outstanding US dollar debt. The net unrealized gain/loss for each of the periods presented included the impact of cross currency swaps (three months ended March 31, 2016 – unrealized loss of $348 million, December 31, 2015 – unrealized gain of $129 million, March 31, 2015 – unrealized gain of $314 million). The US/Canadian dollar exchange rate at March 31, 2016 was US$0.7710 (December 31, 2015 – US$0.7225, March 31, 2015 – US$0.7885).

INCOME TAXES

	Three Months Ended		
($ millions, except income tax rates)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
North America [1]	**$ (119)**	$ (66)	$ 8
North Sea	**(23)**	(18)	(64)
Offshore Africa	**4**	5	2
PRT recovery – North Sea	**(55)**	(71)	(54)
Other taxes	**1**	2	3
Current income tax recovery	**(192)**	(148)	(105)
Deferred income tax expense (recovery)	**33**	(1)	(289)
Deferred PRT (recovery) expense – North Sea	**(204)**	(32)	7
Deferred income tax recovery	**(171)**	(33)	(282)
	(363)	(181)	(387)
Income tax rate and other legislative changes [2]	**114**	—	228
	$ (249)	$ (181)	$ (159)
Effective income tax rate on adjusted net earnings from operations [3]	**29%**	59%	106%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's deferred income tax liability of $114 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million.

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The current PRT recovery in the North Sea in the first quarter of 2016 and the comparable quarters included the impact of carrybacks of abandonment expenditures related to the Murchison platform.

The effective income tax rate for the first quarter of 2016 and the comparable quarters included the impact of non-taxable items in North America and the North Sea as well as the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

In March 2016, the UK government enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these income tax rate changes, the Company's deferred PRT liability was reduced by $228 million and the deferred income tax liability was increased by $114 million.

The UK government is also proposing to reduce the supplementary corporation tax rate from 20% to 10% effective January 1, 2016, subject to legislative approval.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

For 2016, based on forward commodity prices and the current availability of tax pools, the Company now expects to recognize current income tax recoveries of $200 million to $260 million in Canada and recoveries of $150 million to $200 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2016	Dec 31 2015	Mar 31 2015
Exploration and Evaluation			
Net (proceeds) expenditures [2] [3] [6]	**$ (30)**	$ (885)	$ 46
Property, Plant and Equipment			
Net property acquisitions (disposals) [2] [3] [6]	**31**	(443)	11
Well drilling, completion and equipping	**228**	237	292
Production and related facilities	**121**	154	314
Capitalized interest and other [4]	**24**	26	26
Net expenditures (proceeds)	**404**	(26)	643
Total Exploration and Production	**374**	(911)	689
Oil Sands Mining and Upgrading			
Horizon Phases 2/3 construction costs	**422**	578	406
Sustaining capital	**76**	55	88
Turnaround costs	**6**	5	4
Capitalized interest and other [4]	**81**	68	71
Total Oil Sands Mining and Upgrading	**585**	706	569
Midstream	**1**	2	3
Abandonments [5]	**74**	105	144
Head office	**6**	2	7
Total net capital expenditures (proceeds)	**$ 1,040**	$ (96)	$ 1,412
By segment			
North America [2] [3] [6]	**$ 249**	$ (1,126)	$ 501
North Sea	**16**	34	62
Offshore Africa	**109**	181	126
Oil Sands Mining and Upgrading	**585**	706	569
Midstream	**1**	2	3
Abandonments [5]	**74**	105	144
Head office	**6**	2	7
Total	**$ 1,040**	$ (96)	$ 1,412

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.

(2) Includes Business Combinations.

(3) Includes proceeds from the Company's disposition of properties.

(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

(5) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

(6) The above noted figures include non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets in the fourth quarter of 2015.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the first quarter of 2016 were $1,040 million compared with $1,412 million for the first quarter of 2015 and net proceeds of $96 million for the fourth quarter of 2015. Capital expenditures in the first quarter of 2016 were consistent with the Company's previously announced capital allocation schedule. Capital expenditures in the fourth quarter of 2015 reflected the disposition of a number of North America royalty assets to PrairieSky Ltd. ("PrairieSky"), including exploration and evaluation assets of $488 million and property, plant and equipment of $480 million, for total consideration of $1,658 million including approximately 44.4 million common shares of PrairieSky.

Subject to certain conditions, including applicable Shareholder and regulatory approvals, the Company has agreed with PrairieSky that, by no later than December 31, 2016, it will distribute sufficient common shares of PrairieSky to the Company's shareholders so that the Company, after such distribution, will hold less than 10% of the issued and outstanding common shares of PrairieSky.

On March 21, 2016, in connection with the proposed distribution, the Company received an Interim Order in respect of a proposed Plan of Arrangement, which remains subject to Shareholder, Board of Directors and applicable regulatory approvals. If and when implemented, the proposed Plan of Arrangement would satisfy the agreement to distribute the PrairieSky common shares.

Drilling Activity

	Three Months Ended		
(number of wells)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Net successful natural gas wells	**4**	4	9
Net successful crude oil wells (1)	**8**	2	42
Dry wells	**–**	–	2
Stratigraphic test / service wells	**199**	73	86
Total	**211**	79	139
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 26% of the total net capital expenditures for the first quarter of 2016 compared with approximately 40% for the first quarter of 2015.

During the first quarter of 2016, the Company targeted 4 net natural gas wells, including 1 well in Northeast British Columbia and 3 wells in Northwest Alberta. The Company also targeted 7 net crude oil wells. Of the 7 wells, 6 net primary heavy crude oil wells were drilled in the Company's Northern Plains region and 1 light crude oil well was drilled outside the Northern Plains region.

Overall thermal oil production for the first quarter of 2016 averaged approximately 118,100 bbl/d compared with approximately 146,100 bbl/d for the first quarter of 2015 and approximately 135,100 bbl/d for the fourth quarter of 2015. Production volumes in the first quarter of 2016 reflected the cyclic nature of thermal oil production at Primrose. In January 2016 the Primrose East pipeline was shut in during the first quarter of 2016 due to pipeline anomalies found on the line during inspection. The repair is expected to be completed in May 2016 and has been reflected in 2016 guidance.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 47,600 bbl/d in the first quarter of 2016 compared with 51,100 bbl/d in the first quarter of 2015 and 49,300 bbl/d in the fourth quarter of 2015.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the first quarter of 2016 continued to focus on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, sour water concentrator, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering, procurement and construction related to tailings retrofit, combined hydrotreater and sulphur recovery units. The Company targets to commission certain key components of the project in the second quarter. Concurrent with the turnaround in the third quarter, the Company will tie-in these key components and commission additional equipment to commence Phase 2B production in the fourth quarter of 2016, adding 45,000 bbl/d of production capacity. The Company targets to complete Phase 3 in the fourth quarter of 2017, adding 80,000 bbl/d of production capacity.

North Sea

No drilling activity is currently planned for 2016. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

Offshore Africa

In the first quarter of 2016, at the Espoir field, Côte d'Ivoire, the Company drilled the sixth gross producing well in the drilling program, adding net production volumes of approximately 6,900 bbl/d to date. The total drilling program consisted of 6 gross producing wells and 1 injector well. In 2016, no additional wells will be drilled in the current program due to the current low commodity price environment and the related impact on the Company's capital expenditures budget.

In the first quarter of 2016, at the Baobab field, Côte d'Ivoire, the Company drilled the sixth gross producing well in the drilling program, adding net production volumes of approximately 13,400 bbl/d to date. In 2016, no additional wells will be drilled in the current program due to the current low commodity price environment and the related impact on the Company's capital expenditures budget. In late December 2015, the Baobab field was temporarily shut-in due to a riser failure, delaying first oil on the fifth gross well. After inspection of the riser system, production was reinstated in late January 2016.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended		
($ millions, except ratios)	**Mar 31 2016**	Dec 31 2015	Mar 31 2015
Working capital (deficit) [1]	**$ 833**	$ 1,193	$ (13)
Long-term debt [2] [3]	**$ 16,564**	$ 16,794	$ 15,689
Share capital	**$ 4,576**	$ 4,541	$ 4,474
Retained earnings	**22,408**	22,765	23,905
Accumulated other comprehensive income	**12**	75	36
Shareholders' equity	**$ 26,996**	$ 27,381	$ 28,415
Debt to book capitalization [3] [4]	**38%**	38%	36%
Debt to market capitalization [3] [5]	**30%**	34%	27%
After-tax return on average common shareholders' equity [6]	**(2%)**	(2%)	11%
After-tax return on average capital employed [3] [7]	**(1%)**	(1%)	8%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt.

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.

(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.

(6) Calculated as net earnings (loss) for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed for the period.

At March 31, 2016, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2015. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash flow from operations supported by the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - In October 2015, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2017. If issued, these securities may be offered separately or together, in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance;
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program.
  - During the first quarter of 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at March 31, 2016, the $750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at March 31, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

During the first quarter of 2016, the Company repaid US$500 million of three-month LIBOR plus 0.375% notes.

At March 31, 2016, the Company had in place bank credit facilities of $7,353 million, of which approximately $2,299 million, net of commercial paper issuances of $649 million, was available for general corporate purposes.

At March 31, 2016, the Company had total US dollar denominated debt with a carrying amount of $10,907 million (US $8,410 million). This included $4,941 million (US$3,810 million) hedged by way of cross currency swaps (US$2,400 million) and foreign currency forwards (US$1,410 million). The fixed repayment amount of these hedging instruments is $4,588 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $353 million to $10,554 million as at March 31, 2016.

Long-term debt was $16,564 million at March 31, 2016, resulting in a debt to book capitalization ratio of 38% (December 31, 2015 – 38%; March 31, 2015 – 36%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at March 31, 2016 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At May 4, 2016 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at March 31, 2016, there were 1,095,662,000 common shares outstanding (December 31, 2015 – 1,094,668,000 common shares) and 69,859,000 stock options outstanding. As at May 3, 2016, the Company had 1,097,398,000 common shares outstanding and 67,890,000 stock options outstanding.

On March 2, 2016, the Board of Directors declared a regular quarterly dividend of $0.23 per common share. On an annualized basis, the dividend of $0.92 per common share remains unchanged from the previous annual dividend rate. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

The Company's Normal Course Issuer Bid announced in 2015 expired April 2016 and was not renewed. For the three months ended March 31, 2016, the Company did not purchase any common shares for cancellation.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at March 31, 2016:

($ millions)		Remaining 2016		2017		2018		2019		2020		Thereafter
Product transportation and pipeline	$	324	$	347	$	299	$	254	$	241	$	1,265
Offshore equipment operating leases and offshore drilling	$	173	$	92	$	70	$	25	$	1	$	—
Long-term debt (1) (2)	$	973	$	1,427	$	2,758	$	2,745	$	2,200	$	6,531
Interest and other financing expense (3)	$	447	$	584	$	502	$	440	$	394	$	4,323
Office leases	$	32	$	42	$	42	$	43	$	42	$	193
Other	$	109	$	38	$	48	$	1	$	—	$	—

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.

(2) At March 31, 2016, the Company had US$250 million of 6.00% debt securities due August 2016, hedged by way of a cross currency swap with a principal repayment amount fixed at $279 million.

(3) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at March 31, 2016.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2015 and the unaudited interim financial statements for the three months ended March 31, 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2016	Dec 31 2015
ASSETS			
Current assets			
Cash and cash equivalents		**$ 15**	$ 69
Accounts receivable		**1,028**	1,277
Current income taxes		**717**	677
Inventory		**590**	525
Prepaids and other		**185**	162
Investment in PrairieSky Royalty Ltd.	5	**1,095**	974
Current portion of other long-term assets	6	**48**	375
		3,678	4,059
Exploration and evaluation assets	3	**2,538**	2,586
Property, plant and equipment	4	**51,049**	51,475
Other long-term assets	6	**1,097**	1,155
		$ 58,362	$ 59,275
LIABILITIES			
Current liabilities			
Accounts payable		**$ 433**	$ 571
Accrued liabilities		**2,112**	2,089
Current portion of long-term debt	7	**973**	1,729
Current portion of other long-term liabilities	8	**300**	206
		3,818	4,595
Long-term debt	7	**15,591**	15,065
Other long-term liabilities	8	**2,827**	2,890
Deferred income taxes		**9,130**	9,344
		31,366	31,894
SHAREHOLDERS' EQUITY			
Share capital	10	**4,576**	4,541
Retained earnings		**22,408**	22,765
Accumulated other comprehensive income	11	**12**	75
		26,996	27,381
		$ 58,362	$ 59,275

Commitments and contingencies (note 15).

Approved by the Board of Directors on May 4, 2016

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Mar 31 2016**	Mar 31 2015
Product sales		**$ 2,263**	$ 3,226
Less: royalties		**(85)**	(192)
Revenue		**2,178**	3,034
Expenses			
Production		**1,022**	1,253
Transportation and blending		**510**	635
Depletion, depreciation and amortization	4	**1,219**	1,355
Administration		**86**	104
Share-based compensation	8	**117**	64
Asset retirement obligation accretion	8	**36**	43
Interest and other financing expense		**92**	86
Risk management activities	14	**70**	(242)
Foreign exchange (gain) loss		**(315)**	360
Gain on disposition of properties	3	**(32)**	—
(Gain) loss from investments	5, 6	**(159)**	15
		2,646	3,673
Loss before taxes		**(468)**	(639)
Current income tax recovery	9	**(192)**	(105)
Deferred income tax recovery	9	**(171)**	(282)
Net loss		**$ (105)**	$ (252)
Net loss per common share			
Basic	13	**$ (0.10)**	$ (0.23)
Diluted	13	**$ (0.10)**	$ (0.23)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Mar 31 2016**	Mar 31 2015
Net loss	**$ (105)**	$ (252)
Items that may be reclassified subsequently to net earnings (loss)		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized loss during the period, net of taxes of $3 million (2015 – $1 million)	**(24)**	(9)
Reclassification to net earnings (loss), net of taxes of $2 million (2015 – $nil)	**10**	(2)
	(14)	(11)
Foreign currency translation adjustment		
Translation of net investment	**(49)**	(4)
Other comprehensive loss, net of taxes	**(63)**	(15)
Comprehensive loss	**$ (168)**	$ (267)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2016**	Mar 31 2015
Share capital	10		
Balance – beginning of period		**$ 4,541**	$ 4,432
Issued upon exercise of stock options		**30**	35
Previously recognized liability on stock options exercised for common shares		**5**	7
Balance – end of period		**4,576**	4,474
Retained earnings			
Balance – beginning of period		**22,765**	24,408
Net loss		**(105)**	(252)
Dividends on common shares	10	**(252)**	(251)
Balance – end of period		**22,408**	23,905
Accumulated other comprehensive income	11		
Balance – beginning of period		**75**	51
Other comprehensive loss, net of taxes		**(63)**	(15)
Balance – end of period		**12**	36
Shareholders' equity		**$ 26,996**	$ 28,415

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2016	Mar 31 2015
Operating activities			
Net loss		**$ (105)**	$ (252)
Non-cash items			
Depletion, depreciation and amortization		**1,219**	1,355
Share-based compensation		**117**	64
Asset retirement obligation accretion		**36**	43
Unrealized risk management loss		**74**	14
Unrealized foreign exchange (gain) loss		**(334)**	413
(Gain) loss from investments	5, 6	**(147)**	15
Deferred income tax recovery		**(171)**	(282)
Gain on disposition of properties		**(32)**	—
Other		**19**	42
Abandonment expenditures		**(74)**	(144)
Net change in non-cash working capital		**(21)**	(14)
		581	1,254
Financing activities			
Issue of bank credit facilities and commercial paper, net		**1,130**	877
Repayment of US dollar debt securities		**(555)**	—
Issue of common shares on exercise of stock options		**30**	35
Dividends on common shares		**—**	(245)
Net change in non-cash working capital		**—**	(13)
		605	654
Investing activities			
Net proceeds (expenditures) on exploration and evaluation assets		**30**	(46)
Net expenditures on property, plant and equipment		**(996)**	(1,222)
Investment in other long-term assets		**(99)**	(112)
Net change in non-cash working capital		**(175)**	(519)
		(1,240)	(1,899)
(Decrease) increase in cash and cash equivalents		**(54)**	9
Cash and cash equivalents – beginning of period		**69**	25
Cash and cash equivalents – end of period		**$ 15**	$ 34
Interest paid, net		**$ 182**	$ 156
Income taxes (received) paid		**$ (117)**	$ 209

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2015, except as discussed in Note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2015.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2016, the Company adopted the amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. The Company adopted this amendment prospectively. Adoption of this amended standard did not result in a significant impact to the Company's consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2015	$ 2,500	$ —	$ 86	$ —	$ 2,586
Additions	**—**	**—**	**5**	**—**	**5**
Transfers to property, plant and equipment	**(48)**	**—**	**—**	**—**	**(48)**
Disposals/derecognitions	**(3)**	**—**	**—**	**—**	**(3)**
Foreign exchange adjustments	**—**	**—**	**(2)**	**—**	**(2)**
At March 31, 2016	**$ 2,449**	**$ —**	**$ 89**	**$ —**	**$ 2,538**

During the three months ended March 31, 2016, the Company disposed of a number of North America exploration and evaluation assets totalling $3 million for consideration of $35 million, resulting in a pre-tax gain on sale of properties of $32 million.

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2015	$ 60,540	$ 7,414	$ 5,173	$ 24,343	$ 577	$ 378	$ 98,425
Additions	**285**	**16**	**104**	**585**	**1**	**6**	**997**
Transfers from E&E assets	**48**	**—**	**—**	**—**	**—**	**—**	**48**
Disposals/derecognitions	**(84)**	**—**	**—**	**(15)**	**—**	**—**	**(99)**
Foreign exchange adjustments and other	**—**	**(469)**	**(331)**	**—**	**—**	**—**	**(800)**
At March 31, 2016	**$ 60,789**	**$ 6,961**	**$ 4,946**	**$ 24,913**	**$ 578**	**$ 384**	**$ 98,571**
Accumulated depletion and depreciation							
At December 31, 2015	$ 35,347	$ 5,264	$ 3,659	$ 2,294	$ 132	$ 254	$ 46,950
Expense	**889**	**110**	**61**	**147**	**3**	**9**	**1,219**
Disposals/derecognitions	**(84)**	**—**	**—**	**(15)**	**—**	**—**	**(99)**
Foreign exchange adjustments and other	**9**	**(338)**	**(225)**	**6**	**—**	**—**	**(548)**
At March 31, 2016	**$ 36,161**	**$ 5,036**	**$ 3,495**	**$ 2,432**	**$ 135**	**$ 263**	**$ 47,522**
Net book value							
- at March 31, 2016	**$ 24,628**	**$ 1,925**	**$ 1,451**	**$ 22,481**	**$ 443**	**$ 121**	**$ 51,049**
- at December 31, 2015	$ 25,193	$ 2,150	$ 1,514	$ 22,049	$ 445	$ 124	$ 51,475

Project costs not subject to depletion and depreciation	**Mar 31 2016**	Dec 31 2015
Horizon	**$ 6,410**	$ 6,017
Kirby Thermal Oil Sands – North	**$ 824**	$ 816

During the three months ended March 31, 2016, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of $31 million. These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of $1 million. No net deferred income liabilities or pre-tax gains were recognized on these acquisitions.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the three months ended March 31, 2016, pre-tax interest of $61 million (March 31, 2015 – $58 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (March 31, 2015 – 4.0%).

5. INVESTMENT IN PRAIRIESKY ROYALTY LTD.

In connection with the disposal of a number of North America royalty income assets in 2015, the Company acquired approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky"). As the Company's investment constitutes less than 20% of the outstanding shares of PrairieSky, the investment is accounted for at fair value through profit or loss and is remeasured at each reporting date. As at March 31, 2016, the Company's investment in PrairieSky of $1,095 million (December 31, 2015 – $974 million) has been classified as a current asset.

The gain from investment related to PrairieSky was comprised as follows:

	Three Months Ended	
	Mar 31 2016	Mar 31 2015
Fair value gain from PrairieSky	**$ 121**	$ —
Dividend income from PrairieSky	**12**	—
	$ 133	$ —

Subject to certain conditions, including applicable Shareholder and regulatory approvals, the Company has agreed with PrairieSky that, by no later than December 31, 2016, it will distribute sufficient common shares of PrairieSky to the Company's shareholders so that the Company, after such distribution, will hold less than 10% of the issued and outstanding common shares of PrairieSky.

On March 21, 2016, in connection with the proposed distribution, the Company received an Interim Order in respect of a proposed Plan of Arrangement, which remains subject to Shareholder, Board of Directors and applicable regulatory approvals. If and when implemented, the proposed Plan of Arrangement would satisfy the agreement to distribute the PrairieSky common shares.

6. OTHER LONG-TERM ASSETS

	Mar 31 2016	Dec 31 2015
Investment in North West Redwater Partnership	**$ 280**	$ 254
North West Redwater Partnership subordinated debt (1)	**361**	254
Risk Management (note 14)	**363**	854
Other	**141**	168
	1,145	1,530
Less: current portion	**48**	375
	$ 1,097	$ 1,155

(1) Includes accrued interest.

Investment in North West Redwater Partnership

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership's voting and decision-making structure and legal form. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2013, the Company, along with APMC, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). During the first quarter of 2016, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the first quarter of 2016, Redwater Partnership issued $550 million of 4.25% series F senior secured bonds due June 2029, and $300 million of 4.75% series G senior secured bonds due June 2037. As at March 31, 2016, Redwater Partnership had additional borrowings of $982 million under its secured $3,500 million syndicated credit facility.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

During the three months ended March 31, 2016, the Company recognized an equity gain from Redwater Partnership of $26 million (March 31, 2015 – loss of $15 million).

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

7. LONG-TERM DEBT

	Mar 31 2016	Dec 31 2015
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 3,227**	$ 2,385
Medium-term notes	**2,500**	2,500
	5,727	4,885
US dollar denominated debt, unsecured		
Bank credit facilities (March 31, 2016 - US$910 million; December 31, 2015 - US$657 million)	**1,178**	909
Commercial paper (US$500 million)	**649**	692
US dollar debt securities (March 31, 2016 - US$7,000 million; December 31, 2015 - US$7,500 million)	**9,080**	10,380
	10,907	11,981
Long-term debt before transaction costs and original issue discounts, net	**16,634**	16,866
Less: original issue discounts, net (1)	**(10)**	(10)
transaction costs (1) (2)	**(60)**	(62)
	16,564	16,794
Less: current portion of commercial paper	**649**	692
current portion of other long-term debt (1) (2)	**324**	1,037
	$ 15,591	$ 15,065

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank Credit Facilities and Commercial Paper

As at March 31, 2016, the Company had in place bank credit facilities of $7,353 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- a $750 million non-revolving term credit facility maturing February 2019;
- a $125 million non-revolving term credit facility maturing February 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2019;
- a $2,425 million revolving syndicated credit facility maturing June 2020; and
- a £15 million demand credit facility related to the Company's North Sea operations.

Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

During the first quarter of 2016, the Company prepaid $250 million of the previously outstanding $1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at March 31, 2016, the $750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn at March 31, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

Borrowings under the $1,500 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at March 31, 2016, the $1,500 million facility was fully drawn.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2016, was 2.0% (March 31, 2015 – 1.8%), and on total long-term debt outstanding for the three months ended March 31, 2016 was 3.9% (March 31, 2015 – 4.0%).

At March 31, 2016, letters of credit and guarantees aggregating $297 million, including a $39 million financial guarantee related to Horizon and $156 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

Medium-Term Notes

In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

During the first quarter of 2016, the Company repaid US$500 million of three-month LIBOR plus 0.375% notes.

In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

8. OTHER LONG-TERM LIABILITIES

	Mar 31 2016	Dec 31 2015
Asset retirement obligations	**$ 2,838**	$ 2,950
Share-based compensation	**263**	128
Risk management (note 14)	**10**	—
Other	**16**	18
	3,127	3,096
Less: current portion	**300**	206
	$ 2,827	$ 2,890

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.9% (December 31, 2015 – 5.9%). Reconciliations of the discounted asset retirement obligations were as follows:

	Mar 31 2016	Dec 31 2015
Balance – beginning of period	**$ 2,950**	$ 4,221
Liabilities incurred	**—**	7
Liabilities acquired, net	**1**	129
Liabilities settled	**(74)**	(370)
Asset retirement obligation accretion	**36**	173
Revision of cost, inflation rates and timing estimates	**—**	(313)
Change in discount rate	**—**	(1,150)
Foreign exchange adjustments	**(75)**	253
Balance – end of period	**2,838**	2,950
Less: current portion	**76**	101
	$ 2,762	$ 2,849

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

	Mar 31 2016	Dec 31 2015
Balance – beginning of period	**$ 128**	$ 203
Share-based compensation expense (recovery)	**117**	(46)
Cash payment for stock options surrendered	**—**	(1)
Transferred to common shares	**(5)**	(18)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	**23**	(10)
Balance – end of period	**263**	128
Less: current portion	**214**	105
	$ 49	$ 23

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
	Mar 31 2016	Mar 31 2015
Current corporate income tax (recovery) expense – North America	**$ (119)**	$ 8
Current corporate income tax recovery – North Sea	**(23)**	(64)
Current corporate income tax expense – Offshore Africa	**4**	2
Current PRT [(1)] recovery – North Sea	**(55)**	(54)
Other taxes	**1**	3
Current income tax recovery	**(192)**	(105)
Deferred corporate income tax expense (recovery)	**33**	(289)
Deferred PRT [(1)] (recovery) expense – North Sea	**(204)**	7
Deferred income tax recovery	**(171)**	(282)
Income tax recovery	**$ (363)**	$ (387)

(1) Petroleum Revenue Tax.

In March 2016, the UK government enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these income tax changes, the Company's deferred PRT liability was reduced by $228 million and the deferred income tax liability was increased by $114 million.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2016	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,094,668**	**$ 4,541**
Issued upon exercise of stock options	**994**	**30**
Previously recognized liability on stock options exercised for common shares	**—**	**5**
Balance – end of period	**1,095,662**	**$ 4,576**

Dividend Policy

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 2, 2016, the Board of Directors declared a quarterly dividend of $0.23 per common share ($0.23 per common share on March 4, 2015), beginning with the dividend payable on April 1, 2016.

Normal Course Issuer Bid

The Company's Normal Course Issuer Bid, announced in 2015, expired April 2016 and was not renewed. For the three months ended March 31, 2016, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2016:

	Three Months Ended Mar 31, 2016		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**74,615**	**$**	**34.88**
Granted	**4,668**	**$**	**23.24**
Surrendered for cash settlement	**(41)**	**$**	**31.36**
Exercised for common shares	**(994)**	**$**	**29.57**
Forfeited	**(8,389)**	**$**	**40.90**
Outstanding – end of period	**69,859**	**$**	**33.45**
Exercisable – end of period	**23,139**	**$**	**34.69**

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

		Mar 31 2016		Mar 31 2015
Derivative financial instruments designated as cash flow hedges	**$**	**44**	$	83
Foreign currency translation adjustment		**(32)**		(47)
	$	**12**	$	36

12. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At March 31, 2016, the ratio was within the target range at 38%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Mar 31 2016	Dec 31 2015
Long-term debt [1]	**$ 16,564**	$ 16,794
Total shareholders' equity	**$ 26,996**	$ 27,381
Debt to book capitalization	**38%**	38%

(1) Includes the current portion of long-term debt.

13. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended	
	Mar 31 2016	Mar 31 2015
Weighted average common shares outstanding – basic (thousands of shares)	**1,094,915**	1,092,350
Effect of dilutive stock options (thousands of shares)	**—**	—
Weighted average common shares outstanding – diluted (thousands of shares)	**1,094,915**	1,092,350
Net loss	**$ (105)**	$ (252)
Net loss per common share – basic	**$ (0.10)**	$ (0.23)
– diluted	**$ (0.10)**	$ (0.23)

14. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

	Mar 31, 2016				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	$ 1,028	$ —	$ —	$ —	$ 1,028
Investment in PrairieSky	—	1,095	—	—	1,095
Other long-term assets	361	—	363	—	724
Accounts payable	—	—	—	(433)	(433)
Accrued liabilities	—	—	—	(2,112)	(2,112)
Other long-term liabilities	—	(37)	27	—	(10)
Long-term debt (1)	—	—	—	(16,564)	(16,564)
	$ 1,389	$ 1,058	$ 390	$ (19,109)	$ (16,272)

	Dec 31, 2015				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,277	$ —	$ —	$ —	$ 1,277
Investment in PrairieSky	—	974	—	—	974
Other long-term assets	254	36	818	—	1,108
Accounts payable	—	—	—	(571)	(571)
Accrued liabilities	—	—	—	(2,089)	(2,089)
Long-term debt (1)	—	—	—	(16,794)	(16,794)
	$ 1,531	$ 1,010	$ 818	$ (19,454)	$ (16,095)

(1) Includes the current portion of long-term debt.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt as noted below. The fair values of the Company's recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

	Mar 31, 2016			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3**
Investment in PrairieSky (3)	$ 1,095	$ 1,095	$ —	$ —
Other long-term assets (4)	$ 724	$ —	$ 363	$ 361
Other long-term liabilities	$ (10)	$ —	$ (10)	$ —
Fixed rate long-term debt (5) (6)	$ (11,510)	$ (11,073)	$ —	$ —

	Dec 31, 2015			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3
Investment in PrairieSky [3]	$ 974	$ 974	$ —	$ —
Other long-term assets [4]	$ 1,108	$ —	$ 854	$ 254
Fixed rate long-term debt [5] [6]	$ (12,808)	$ (12,431)	$ —	$ —

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair value of the investment in PrairieSky is based on quoted market prices.

(4) The fair value of North West Redwater Partnership subordinated debt is based on the present value of future cash receipts.

(5) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(6) Includes the current portion of fixed rate long-term debt.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	**Mar 31, 2016**	Dec 31, 2015
Derivatives held for trading		
Foreign currency forward contracts	**$ (37)**	$ 36
Cash flow hedges		
Foreign currency forward contracts	**(39)**	30
Cross currency swaps	**429**	788
	$ 353	$ 854
Included within:		
Current portion of other long-term (liabilities) assets	**$ (10)**	$ 305
Other long-term assets	**363**	549
	$ 353	$ 854

For the three months ended March 31, 2016, the Company recognized a loss of $1 million (year ended December 31, 2015 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Risk Management

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The changes in estimated fair values of derivative financial instruments included in the risk management asset were recognized in the financial statements as follows:

Asset (liability)		**Mar 31 2016**		Dec 31 2015
Balance – beginning of period	**$**	**854**	$	599
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(74)**		(374)
Foreign exchange		**(412)**		669
Other comprehensive loss		**(15)**		(40)
Balance – end of period		**353**		854
Less: current portion		**(10)**		305
	$	**363**	$	549

Net losses (gains) from risk management activities were as follows:

	Three Months Ended			
		Mar 31 2016		Mar 31 2015
Net realized risk management gain	**$**	**(4)**	$	(256)
Net unrealized risk management loss		**74**		14
	$	**70**	$	(242)

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At March 31, 2016, the Company had no commodity derivative financial instruments outstanding.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2016, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At March 31, 2016, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Apr 2016	—	Aug 2016	US$250	1.116	6.00%	5.40%
	Apr 2016	—	May 2017	US$1,100	1.170	5.70%	5.10%
	Apr 2016	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Apr 2016	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at March 31, 2016 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at March 31, 2016, the Company had US$2,323 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$1,410 million designated as cash flow hedges.

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2016, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At March 31, 2016, the Company had net risk management assets of $404 million with specific counterparties related to derivative financial instruments (December 31, 2015 – $854 million).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	433	$	—	$	—	$	—
Accrued liabilities	$	2,112	$	—	$	—	$	—
Other long-term liabilities	$	10	$	—	$	—	$	—
Long-term debt (1)	$	973	$	2,724	$	6,406	$	6,531

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		Remaining 2016		2017		2018		2019		2020		Thereafter
Product transportation and pipeline	$	324	$	347	$	299	$	254	$	241	$	1,265
Offshore equipment operating leases and offshore drilling	$	173	$	92	$	70	$	25	$	1	$	—
Office leases	$	32	$	42	$	42	$	43	$	42	$	193
Other	$	109	$	38	$	48	$	1	$	—	$	—

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

16. SEGMENTED INFORMATION

	North America		North Sea		Offshore Africa		Total Exploration and Production	
	Three Months Ended		Three Months Ended		Three Months Ended		Three Months Ended	
	Mar 31		Mar 31		Mar 31		Mar 31	
(millions of Canadian dollars, unaudited)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Segmented product sales	**1,512**	2,334	**121**	152	**100**	67	**1,733**	2,553
Less: royalties	**(79)**	(177)	**—**	—	**(5)**	(3)	**(84)**	(180)
Segmented revenue	**1,433**	2,157	**121**	152	**95**	64	**1,649**	2,373
Segmented expenses								
Production	**567**	751	**120**	134	**34**	15	**721**	900
Transportation and blending	**493**	620	**10**	13	**1**	1	**504**	634
Depletion, depreciation and amortization	**897**	1,104	**111**	87	**61**	22	**1,069**	1,213
Asset retirement obligation accretion	**17**	23	**9**	9	**3**	3	**29**	35
Realized risk management activities	**(4)**	(256)	**—**	—	**—**	—	**(4)**	(256)
Gain on disposition of properties	**(32)**	—	**—**	—	**—**	—	**(32)**	—
(Gain) loss from investments	**(133)**	—	**—**	—	**—**	—	**(133)**	—
Total segmented expenses	**1,805**	2,242	**250**	243	**99**	41	**2,154**	2,526
Segmented earnings (loss) before the following	**(372)**	(85)	**(129)**	(91)	**(4)**	23	**(505)**	(153)
Non–segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Unrealized risk management activities								
Foreign exchange (gain) loss								
Total non–segmented expenses								
Loss before taxes								
Current income tax recovery								
Deferred income tax recovery								
Net loss								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three Months Ended Mar 31		Midstream Three Months Ended Mar 31		Inter–segment elimination and other Three Months Ended Mar 31		Total Three Months Ended Mar 31	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Segmented product sales	**524**	660	**26**	35	**(20)**	(22)	**2,263**	3,226
Less: royalties	**(1)**	(12)	**—**	—	**—**	—	**(85)**	(192)
Segmented revenue	**523**	648	**26**	35	**(20)**	(22)	**2,178**	3,034
Segmented expenses								
Production	**297**	346	**6**	9	**(2)**	(2)	**1,022**	1,253
Transportation and blending	**23**	21	**—**	—	**(17)**	(20)	**510**	635
Depletion, depreciation and amortization	**147**	139	**3**	3	**—**	—	**1,219**	1,355
Asset retirement obligation accretion	**7**	8	**—**	—	**—**	—	**36**	43
Realized risk management activities	**—**	—	**—**	—	**—**	—	**(4)**	(256)
Gain on disposition of properties	**—**	—	**—**	—	**—**	—	**(32)**	—
(Gain) loss from investments	**—**	—	**(26)**	15	**—**	—	**(159)**	15
Total segmented expenses	**474**	514	**(17)**	27	**(19)**	(22)	**2,592**	3,045
Segmented earnings (loss) before the following	**49**	134	**43**	8	**(1)**	—	**(414)**	(11)
Non–segmented expenses								
Administration							**86**	104
Share-based compensation							**117**	64
Interest and other financing expense							**92**	86
Unrealized risk management activities							**74**	14
Foreign exchange (gain) loss							**(315)**	360
Total non–segmented expenses							**54**	628
Loss before taxes							**(468)**	(639)
Current income tax recovery							**(192)**	(105)
Deferred income tax recovery							**(171)**	(282)
Net loss							**(105)**	(252)

Capital Expenditures [1]

	Mar 31, 2016			Mar 31, 2015		
	Net expenditures (proceeds)	**Non-cash and fair value changes[2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ (3)**	**$ (48)**	**$ (51)**	$ 44	$ (78)	$ (34)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**5**	**—**	**5**	2	—	2
	$ 2	**$ (48)**	**$ (46)**	$ 46	$ (78)	$ (32)
Property, plant and equipment						
Exploration and Production						
North America	**$ 284**	**$ (35)**	**$ 249**	$ 457	$ (5)	$ 452
North Sea	**16**	**—**	**16**	62	—	62
Offshore Africa	**104**	**—**	**104**	124	—	124
	404	**(35)**	**369**	643	(5)	638
Oil Sands Mining and Upgrading [4]	**585**	**(15)**	**570**	569	(4)	565
Midstream	**1**	**—**	**1**	3	—	3
Head office	**6**	**—**	**6**	7	—	7
	$ 996	**$ (50)**	**$ 946**	$ 1,222	$ (9)	$ 1,213

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(3) The above noted figures do not include the impact of a pre-tax gain on sale of exploration and evaluation assets totaling $32 million.

(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

Segmented Assets

	Mar 31 2016	Dec 31 2015
Exploration and Production		
North America	**$ 29,857**	$ 30,937
North Sea	**2,414**	2,734
Offshore Africa	**1,721**	1,755
Other	**68**	73
Oil Sands Mining and Upgrading	**22,975**	22,598
Midstream	**1,206**	1,054
Head office	**121**	124
	$ 58,362	$ 59,275

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2015. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended March 31, 2016:	
Interest coverage (times)	
Net earnings (loss) (1)	0.5x
Cash flow from operations (2)	9.2x

(1) Net earnings (loss) plus income taxes and interest expense excluding current and deferred PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

(2) Cash flow from operations plus current income taxes and interest expense excluding current PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

Corporate Information

Board of Directors

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N. Murray Edwards, O.C.

Timothy W. Faithfull

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Christopher L. Fong

Ambassador Gordon D. Giffin

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Steve W. Laut

Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.

David A. Tuer

Annette Verschuren, O.C.

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President

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Chief Operating Officer

Lyle G. Stevens
Executive Vice-President, Canadian Conventional

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Réal J.H. Doucet
Senior Vice-President, Horizon Projects

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Senior Vice-President, Exploitation

Terry J. Jocksch
Senior Vice-President, Thermal

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Senior Vice-President, Corporate Development and Land

Paul M. Mendes
Vice-President, Legal, General Counsel and Corporate Secretary

Bill R. Peterson
Senior Vice-President, Production and Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Scott G. Stauth
Senior Vice-President, North America Operations

Betty Yee
Vice-President, Land

International Operations
CNR International (U.K.) Limited
Aberdeen, Scotland

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Vice-President and Managing Director, International

W. David R. Bell
Vice-President, Exploration, International

Barry Duncan
Vice-President, Finance, International

Andrew M. McBoyle
Vice-President, Exploitation, International

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

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